

Appendix A

Additional Vehicle Technology Information

This appendix is intended to supplement the information provided in Chapter II of the EPA Staff Paper on Gasoline Sulfur Issues. It presents more detailed, technical information on how sulfur affects catalysts and the potential impact of sulfur on advanced emission control technologies.

1. Effects of Sulfur on Three-way Catalyst Efficiency

In spark ignition engines, combustion converts sulfur present in the gasoline primarily to sulfur dioxide (SO_2). The nature of the interaction of sulfur with three-way catalysts, and the tenacity of this interaction, depends on a number of factors, including:

- Precious metal, support, and washcoat composition
- Distribution of precious metals and metal oxides
- Catalyst surface area, cell structure, and washcoat layering
- Exhaust oxygen content
- Exhaust temperature

Increasing the sulfur content of gasoline has an almost immediate impact upon the performance of a three-way catalytic converter. SO_2 in the exhaust can react with the support materials, metal oxides within the washcoat, and the precious metals of the catalyst.

a. Precious Metal Sulfur Tolerance and Reversibility

SO_2 is adsorbed and dissociates on the precious metal surfaces, forming adsorbed oxygen and adsorbed sulfide. Adsorbed sulfide effectively blocks pollutant adsorption to precious metal surfaces at the surface site it is adsorbed to, and at nearby sites due to the electrical charge it imparts. The effect appears to be more severe for palladium (Pd) and palladium-rhodium (Pd-Rh) catalysts than for other precious metal combinations, such as those containing platinum (Pt). In general, sulfur sensitivity of the precious metal catalysts can be described, in order of decreasing sensitivity, as:

$\text{Pd} > \text{Pd-Rh} > \text{Pt-Rh} > \text{Rh}$

Catalysts containing Pd have been an important component in the development of LEV and ULEV vehicles for use in California. Pd catalysts have demonstrated improved low temperature oxidation of hydrocarbons when compared to Pt-Rh catalysts. Pd-containing catalysts have also demonstrated improved resistance to high-temperature sintering and thermal aging, allowing their use in close-coupled applications and further reducing cold-start

hydrocarbon emissions. Laboratory testing of a Pd three-way catalyst demonstrated a substantial reduction in performance after 4 hours of operation upon switching from the equivalent of a 15 ppm S fuel to a 450 ppm S fuel.¹

Adsorbed sulfide can be oxidized and removed from precious metal surfaces at elevated temperatures (>600°C). It is also possible under such oxidizing conditions that some of the released SO₂ would react with cerium oxide within the washcoat to form cerium oxide and degrade the tolerance of the catalyst to perturbations in air-to-fuel ratio (see below). Sulfide can also be removed from precious metal surfaces under reducing conditions at even higher temperatures (>700°C). Reversal of sulfur inhibition of palladium-containing catalysts appears to be more difficult and slower than for Pt-Rh catalysts. A study of a Pd-only three-way catalyst required a minimum of 10 minutes at temperatures exceeding 650°C for complete reversibility to occur under laboratory conditions.¹ Another laboratory study² showed that a Pt/Pd/Rh tri-metal pelleted catalyst required a rich air-to-fuel ratio and a catalyst temperature of 700°C for full sulfur reversibility. The study also demonstrated that catalysts containing higher cerium oxide contents were more susceptible to sulfur irreversibility. A similar study with a Pd-only catalyst, found that sulfur effects were reversible at 700°C treatment under oxidizing (lean) and then reducing (rich) air-to-fuel ratio mixtures.³ Such cycling of the air-to-fuel ratio has typically been reduced in LEV-technology vehicles in order to improve simultaneous removal of CO, hydrocarbons, and NO_x by the three-way catalyst. Substantial rich excursions at high temperature conditions for purposes of sulfur reversibility could adversely affect hydrocarbon and CO emissions levels under the revised (supplemental) federal test procedure (SFTP).

One possible explanation for the decrease in reversibility found with Pd and Pd-Rh three-way catalysts is that there is evidence that sulfur migrates from the surface of the Pd into the crystal lattice of the metal. Under such circumstances, the Pd would act as a sulfur reservoir. As sulfur is removed from the surface, sulfur would eventually migrate back to the surface to re-establish equilibrium, again blocking the precious metal surface and electrically interfering with nearby surfaces.

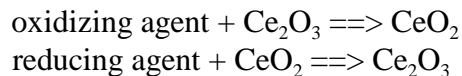
b. Effects of Sulfur on the Management of Oxygen Within the Catalyst

Cerium oxide within the catalyst washcoat can be used to regulate the oxygen content of the exhaust:

¹Beck, D. D., Sommers, J. W., "Impact of Sulfur on the Performance of Vehicle-Aged Palladium Monoliths," Applied Catalysis B, Vol. 6, p. 185-200, 1995.

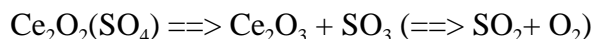
²Beck, D. D., Krueger, M. H., Monroe, D. R. "The Impact of Sulfur on Three-way Catalysts: Storage and Removal," SAE Technical Paper Series, No. 910844, 1991.

³Beck, D. D., Sommers, J. W., "Impact of Sulfur on Three-Way Catalysts: Comparison of Pd and Pt-Rh Commercially Produced Monoliths," 3rd International Congress on Catalysis and Automotive Pollution Control, Brussels, Belgium, April 20-22, 1994.



Oxygen regulation within the catalyst by cerium oxide under lean and rich air-to-fuel ratio conditions reduces the sensitivity of three-way catalysts to air-to-fuel ratio fluctuations. Catalytic reactions which are most sensitive to air-to-fuel ratio fluctuations near the stoichiometric air-to-fuel ratio are thus strongly promoted by cerium oxide forcing the ratio nearer to stoichiometric along the catalyst bed (figures A1, A2). Cerium oxide also promotes reactions that directly oxidize CO under rich conditions and (to a lesser extent) reduce NO under lean conditions (figure A3).

Reactions of metal oxides, such as cerium oxide, with SO₂ under lean conditions to form sulfates, such as Ce₂O₂(SO₄), impedes catalyst function primarily by reducing the ability of the catalyst to manage the oxygen content of the exhaust. Reversal of the sulfation of cerium oxide can occur either through direct thermal decomposition at high temperature (>700 °C):



or by reduction at moderate temperatures (> 500°C), which results in emission of hydrogen sulfide (H₂S)^{4,5}, known for its “rotten egg” odor.

⁴Bazin, P., et al., “Influence of Platinum on Cerium Oxide Sulfation,” Applied Catalysis B, Vol. 13, p. 265-274, 1997.

⁵Waqif, M., et al., “Study of Cerium oxide Sulfation,” Applied Catalysis B, Vol. 11, p. 193-205, 1997.

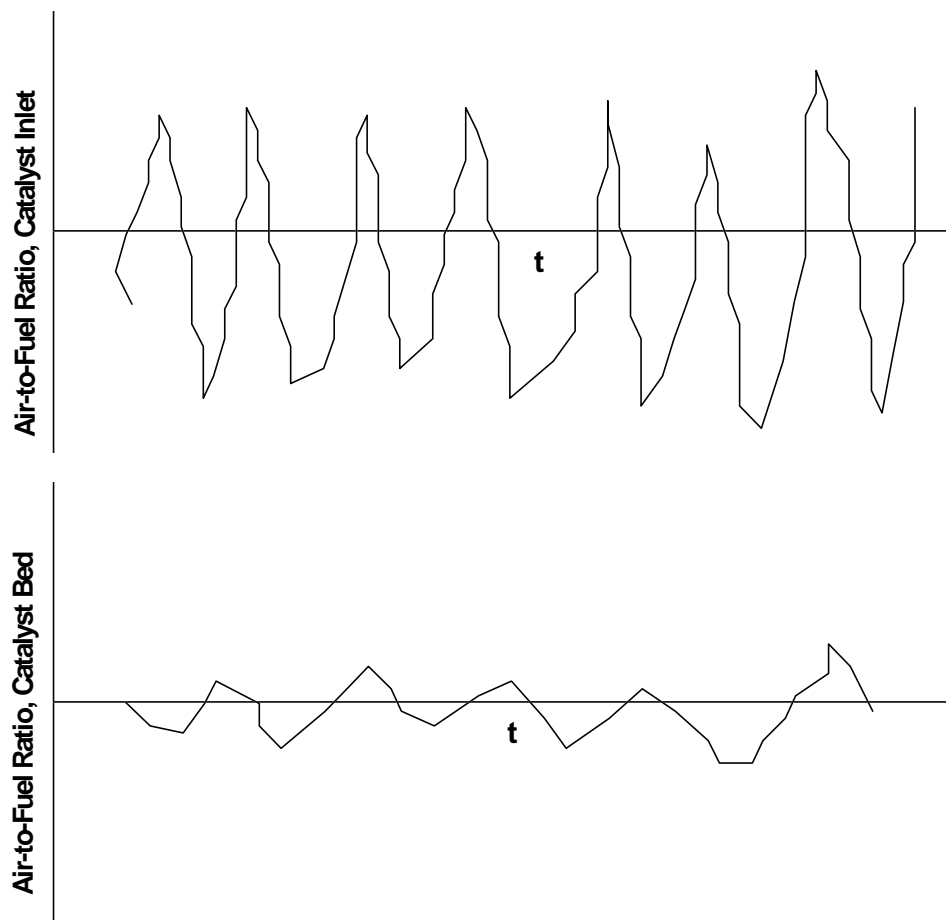


Figure A1: Exhaust oxygen content at the catalyst inlet (top) and after regulation by cerium oxide over the catalyst bed (bottom).

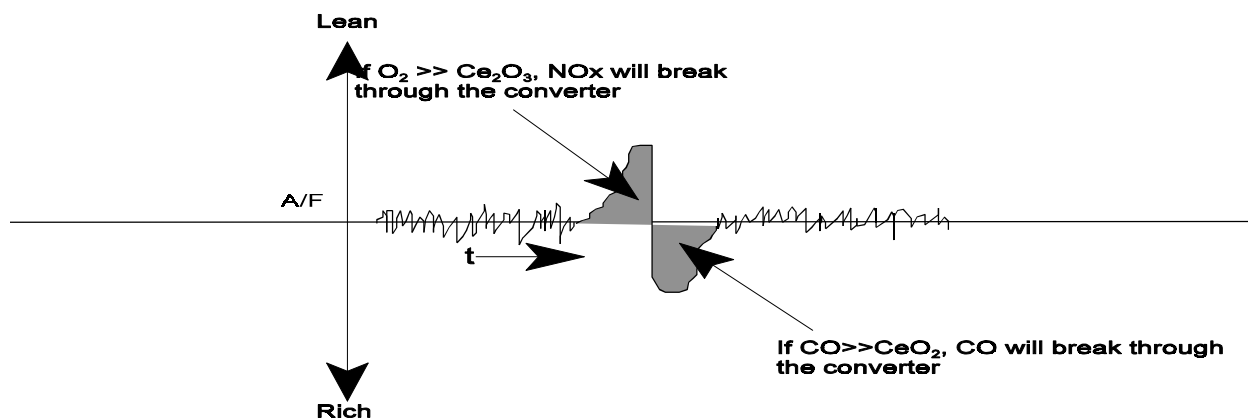


Figure A2: Air-to-fuel ratio perturbations that overwhelm cerium oxide capabilities.

Cerium Oxide Chemistry In Exhaust

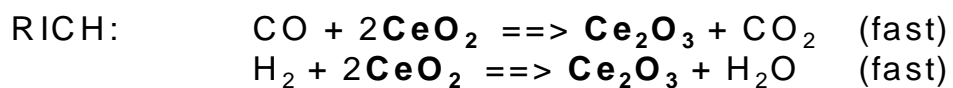
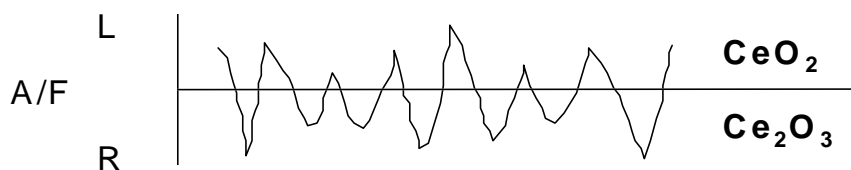
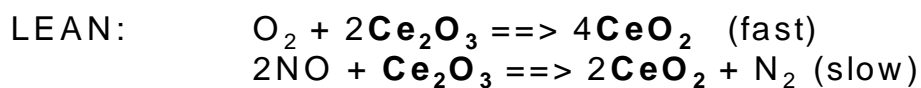


Figure A3: A graphical representation of cerium oxide reactions that manage exhaust oxygen content and directly oxidize CO and reduce NO.

2. Reversibility of Sulfur Inhibition of Three-way Catalysts

The return of catalyst efficiency upon lowering the sulfur content of the gasoline, or sulfur reversibility, may be possible depending on engine operating conditions and the composition and construction of the catalyst.

Although a significant amount of information exists in the literature on sulfur effects and sulfur reversibility using aged three-way catalysts under controlled laboratory conditions, the laboratory studies were typically conducted with pre-mixed gases cycled between slightly reducing and slightly oxidizing. Considering the degree of variability of test conditions and the extremely transient nature of actual vehicle operation, observations and conclusions drawn from data generated in closely controlled laboratory studies may not necessarily apply to actual in-use vehicle performance. The few vehicle studies that have been conducted have focused primarily on the effects of fuel sulfur content on emissions, not on sulfur reversibility.

The vehicle test programs discussed above in Section C of Chapter II utilized special procedures when vehicles switched from one fuel to another to ensure that no sulfur-related effect was carried over from the previous test fuel. These procedures utilized vehicle operation which is not generally representative of typical in-use driving and/or required fuel enrichment beyond the amount available using standard calibrations of the engine management systems. Thus, these programs provided little insight into the reversibility of the sulfur impact.

Thoss, et al.⁶ found CO and NO_x only partially recovered with standard vehicle operation using low-sulfur fuel after high sulfur aging and evaluation. A subsequent treatment at 700 °C with low sulfur fuel lead to some further, but incomplete, recovery. Hydrocarbon emission results were inconclusive due to prolonged rich operation during cold-start. Haren S. Gandhi of Ford Motor Company stated at the CRC Sulfur Symposium that a prototype ULEV Lincoln Towncar exposed to 928 ppm sulfur did not experience full recovery until it was operated under both high temperature and oxidizing (lean) or reducing (rich) conditions.

As discussed in Chapter II, limited test data on sulfur reversibility has been provided by Chrysler, Ford, and API. The Ford data indicated sulfur was irreversible for a prototype ULEV Escort without a special "purge cycle" that introduced high temperature and extremely rich air-to-fuel ratio operation. The LEV Dodge Neon had the same results for hydrocarbons, but sulfur inhibition was reversible for CO and NO_x without any special purge cycle.

A TLEV Mazda Protegé (with advanced catalyst) demonstrated almost complete sulfur recovery for HC, CO, and NO_x also without any special purge cycle. The catalyst temperatures experienced during the FTP, the air-to-fuel ratio, or, in the case of the Protegé, any specifics about the catalyst composition were not provided with the preliminary release of this data, but

⁶Thoss, J. E., Rieck, J. S., Bennet, C. J., "The Impact of Fuel Sulfur Level on FTP Emissions - Effect of PGM Catalyst Type," SAE Technical Paper Series, No. 970737, 1997.

will eventually be provided. Once this information has been obtained, it may be possible to determine why the Escort is only reversible when operated over a rather extreme purge cycle, while the Protégé appears reversible over the FTP. It is possible that the Protégé experiences catalyst temperatures during the FTP cycle in excess of 650°C and also has sufficient amounts of rich and/or lean operation, while the Escort may have lower catalyst temperatures and maintain very tight air-to-fuel ratio at nearly stoichiometric conditions. It may also be possible that the Escort catalyst uses a catalyst design that is less sulfur tolerant and/or that is more difficult to reverse the effects of sulfur inhibition.

Finally, both the laboratory and the vehicle studies are typically lacking in information as to whether high catalyst temperature and rich and/or lean operation need to be continuous or cumulative. For example, how long does the catalyst have to be exposed to temperatures of 700 °C or greater? Can several seconds of these temperatures spread throughout the course of the FTP cycle be sufficient to reverse sulfur inhibition? Or is it necessary to have some length of continuous operation? What conditions will be necessary in actual vehicle usage? Catalyst temperature and air-to-fuel ratio are some of the parameters being measured in the ongoing CRC reversibility study. This information should help illuminate the conditions under which sulfur inhibition of advanced three-way catalyst designs is reversible.

A number of design and operating factors appear to directly or indirectly influence sulfur tolerance and/or sulfur reversibility. In addition to the type of precious metals, higher precious metal loading appears to increase tolerance to sulfur. Higher temperature operation, such as in close coupled applications, appears beneficial for both sulfur tolerance and reversibility of cerium oxide and precious metal components of the catalyst, although such operation can increase thermal aging of the catalyst. Both rich and lean excursions in air-to-fuel ratio may be beneficial from both a standpoint of sulfur tolerance and reversibility. Some vehicles using fuel shut-off during deceleration may provide the necessary oxidizing, high temperature conditions to remove sulfur from precious metal surfaces. Rich operation appears to aid in reducing sulfation of cerium oxide, and when combined with high temperatures, may allow simultaneous removal of sulfur from precious metal surfaces. However, rich excursions may be an impediment to passing SFTP requirements. Conversely, vehicles which use a higher degree of control of the air-to-fuel ratio through the engine management system require less cerium oxide in their catalyst formulations, and thus may be less prone to the effects of cerium oxide sulfation on management of the oxygen content of the exhaust.

3. Effects of Sulfur on Lean NO_x Catalysts

Recently developed gasoline-direct-injection (GDI) engines offer fuel consumption benefits approaching those of turbocharged, direct-injection diesel engines, with PM emissions nearer to those of conventional spark ignition gasoline engines. Although the very lean (20:1 to 40:1 air-to-fuel) operation made possible by GDI reduces engine out NO_x emissions, conventional three-way catalyst designs are ineffective for further NO_x control under these conditions. More conventional spark ignition engines use closed loop control systems to maintain a fuel-to-air ratio near stoichiometric to allow operation within the narrow window of

operating conditions necessary for efficient removal of CO, hydrocarbons, and NO_x with conventional three-way catalyst designs. Under conditions where the partial pressure of O₂ in the exhaust significantly exceeds the partial pressure of NO, as with GDI engines during much of their operation, the rate of NO reduction with conventional three-way catalysts decreases substantially. Thus, for NO_x control to levels for vehicles equipped with lean GDI engines to be at least equivalent to those of stoichiometric/three-way catalyst-equipped vehicles, the use of NO adsorption or "NO_x storage traps" with cycling of the air-to-fuel ratio, and/or the use of selective catalytic reduction (SCR) will be necessary. These types of lean-operation catalyst systems are collectively referred to as "lean-NO_x" catalysts.

Effective SCR reductants include urea and fuel hydrocarbons. SCR systems typically use a base metal catalyst that is capable of reducing NO in the presence of a suitable reductant. Use of a hydrocarbon reductant eliminates the need for on-board storage of a separate reductant, and is typically accomplished by direct injection of fuel during the expansion stroke. SCR lean-NO_x catalyst strategies appear to be relatively insensitive to gasoline sulfur content up to at least 300 ppm of sulfur, but have lower NO_x removal efficiency (<60%) and are effective over a narrower range of exhaust temperatures than lean-NO_x catalysts using NO_x storage⁷. Based on information provided by manufacturers, it does not appear feasible for GDI engines to achieve NLEV LDV NO_x emissions levels using SCR-only lean-NO_x strategies.

A NO_x trap can be used either upstream of a catalyst substrate, or can be incorporated in the washcoat in a portion of the catalytic converter. The trap material is typically an alkaline or alkaline earth material, with barium and calcium being two commonly used materials. First, NO is oxidized to NO₂ over a platinum catalyst during lean operation. The NO₂ adsorbs to the NO_x trap as, for example, barium or calcium nitrate. Under reducing (rich) conditions, the nitrate is reduced (either directly or indirectly) and N₂ is released. Only slightly rich ($0.95 < \lambda < 0.98$) is necessary for nitrate reduction. GDI engines can be cycled between lean operation and stoichiometric or even rich operation. Significant amounts of operation away from the typical lean operation increase fuel consumption, but a typical lean adsorb/rich purge rate (as reported by Johnson-Matthey) is approximately 2 minutes of lean NO_x adsorption/1 second of rich purging. In addition, some GDI engines use near stoichiometric conditions to provide a "high torque" mode of operation during acceleration that can be used for purging. Another possibility is to use NO_x storage in combination with late fuel injection to force purging of the stored NO_x in order to prevent driveability problems from occurring when changing from extreme lean operation (>40:1 air-to-fuel in some cases) to rich operation.

NO_x trapping and reduction has a much higher NO_x removal efficiency (>90% in some instances) and is effective over a broader range of exhaust temperatures. It also appears to be significantly less tolerant of sulfur. The trap materials adsorb SO₂ continuously to form barium or calcium sulfates, and eventually depleting the barium or calcium available for nitrate

⁷Mitsubishi Motors, "4G93 GDI Engine: Technical Information," Available from Mitsubishi Motors, or on the World-Wide-Web: <<http://www.mitsubishi-motors.no/gdi>>, 1998.

formation and severely degrading the performance of the catalyst. Tests by Mitsubishi of a prototype lean-NO_x catalyst using a NO_x storage trap showed significant degradation after 8000 km of aging using gasoline with 100 ppm of sulfur. The catalyst originally performed at greater than 90% removal efficiency for NO_x, but degraded to 40 to 60% NO_x removal efficiency after aging on the higher sulfur gasoline. The effect will occur at any level of fuel sulfur in the gasoline, and is essentially an integrative effect, occurring more rapidly at higher fuel sulfur levels. Purging of the sulfate is similar in principle to nitrate purging, requiring slightly rich operation, but the reaction rates are much slower and would require longer periods of rich operation. Automotive and catalyst manufacturers have stated that using a 100 to 300 ppm sulfur fuel would necessitate enough rich operation for sulfate purging that the fuel efficiency benefits of using a lean GDI combustion strategy would be essentially negated. Fuel efficiency using a 20 to 50 ppm sulfur fuel, including rich operation for nitrate and sulfate purging, approaches that of a direct injection turbo-charged diesel engine at near NLEV NO_x levels and with PM levels comparable to those conventional spark-ignition, stoichiometric engines. Considering the coupling of fuel efficiency and NO_x emissions using the NO_x trap technology with GDI, it appears that GDI equipped vehicles will only be feasible at gasoline sulfur levels in the range of those in Japan and California (20 - 40 ppm). It does not appear likely that such vehicles could meet even Tier 1 NO_x levels if required to rely on SCR for NO_x reduction due to higher fuel sulfur levels.

4. Effects of Sulfur on Gasoline Fuel Cells

Fuel cells are electrochemical devices that can be used to generate electricity. They have potential for automotive applications as a relatively high efficiency (>50%) source of electrical power for electric cars. Fuel cells offer the possibility of weight and driving range advantages over more conventional battery-equipped electric cars. Thin-membrane, proton-exchange fuel cell technologies can be provided with the necessary hydrogen fuel from a number of sources, including reforming of methane, methanol, and gasoline. The Office of Advanced Automotive Technologies within the U.S. Department of Energy is currently participating in the development of a process for reforming gasoline to provide hydrogen for automotive fuel cells. They are currently testing a system using California low sulfur gasoline (approximately 40 ppm sulfur). The system uses a zinc oxide bed for trapping sulfur to prevent contamination of the fuel cell. The technology is feasible at higher gasoline sulfur levels, but would require a disposable zinc oxide bed rather than the current system, which currently is approximately sized to last the useful life of the vehicle. The effect of the use of disposable traps on operational costs is not known.

Appendix B

Fuel Sulfur Control Costs

The purpose of this appendix is to provide the reader with additional information regarding the analyses performed by EPA, working with DOE, to estimate the costs of gasoline sulfur control.

1. Refinery Modeling Plan and Modeling Premises

EPA and DOE developed a modeling plan for studying the cost of reducing gasoline sulfur levels. Table B-1 lists the modelling runs, to be performed by Oak Ridge National Laboratory under contract to DOE, that were planned.

While the refinery modeling plan outlined in Table B-1 describes the refinery modeling cases to be run, certain premises must be established as well to set up the refinery model for developing the most representative costs. These premises include: the price of refinery raw materials and products, refinery capacities, and the volumetric demand and production of petroleum products. The approach for establishing these premises, and some of the premises that were derived, are summarized below.

- Only summer cases would be run and the investments made would be amortized over the entire year.
- The potential sulfur reduction program would be implemented in the year 2004 with the Phase II RFG program capital investments presumed to have already been made.
- The current production shares of RFG in PADDs 1 and 3 would apply in the year 2004; these are taken from the Motor Gasoline Watch (DOE, 1997). The result is that RFG represents 62 percent of gasoline production in PADD 1, and 18 percent in PADD 3.
- A summertime base case for year 2004 (including Phase II RFG) would be established using 1997 refinery capacity and/or construction reported in the Petroleum Supply Annual, the Oil and Gas Journal, National Petroleum Council 1993 petroleum industry report and statistics by NPRA. The refinery model would be permitted to add process capacity for the base case, and this investment would be sunk for the study cases which follow.

Table B-1. List of EPA's Planned Refinery Modeling Case Runs			
Model Version^a	LSG Share^b	LSG Sulfur Content^b	Status
Case Runs			
PADD 3 RF	100%	Basecase, 150, 100 & 40 ppm	Completed
PADD 3 R	100%	Basecase & 100 ppm	Completed
PADD 1 RF	100%	Basecase, 150, 100 & 40 ppm	Completed
PADD 1 R	100%	Basecase & 100 ppm	Completed
PADD 3 RF	55%	100 & 40 ppm	Completed
PADD 3 RF	30%	40 ppm	Completed
PADD 3 RF	55%	40 ppm in N/A areas, and 100 ppm in rest of the 22 States	Completed
PADD 1 RF	100%	40 ppm in N/A areas, and 100 ppm in rest of the 22 States	Completed
PADD 2 RF	100%	Basecase & 100 ppm	
PADD 2 RF	70%	100 ppm	
PADD 2 R	100%	Basecase & 100 ppm	
PADD 4 & PADD 5 OC RF	100%	Basecase, 150, 100 & 40 ppm	
Sensitivity Cases			
PADD 3 RF	100%, Investment Adverse ^c	100 ppm	
PADD 3 RF	100%, Grade Split ^d	100 ppm	
PADD 3 RF	100%, Enhanced ^e	100 ppm	
PADD 3 RF	55%, Most Capable Refineries ^f	Basecase & 100 ppm	

a. RF represents version of refinery model without ratio controls; R is the version with such controls, as explained in the text. PADD=Petroleum Administration District for Defense; PADD 5 OC = PADD 5, outside of California.

b. LSG means low sulfur gasoline.

c. Approximates an investment adverse climate by modeling with a higher hurdle rate of return for capital investments.

d. Evaluates the cost of sulfur reduction with both premium and regular grades of gasoline represented in the refinery model.

e. Provides opportunity for the refinery model to select SynSat and CDTECH sulfur removal technologies.

f. Estimates the sulfur reduction cost assuming only low cost sulfur reduction refineries participate.

- Crude oil costs would be based on Petroleum Marketing Monthly (DOE, 1995 and later), and on the National Petroleum Council (NPC, 1993). Historical price differentials and price ratios would be taken from NPC.
- Refinery inputs of raw materials would be estimated using the Petroleum Supply Annual 1996 (DOE, 1997), with extrapolations to the year 2004 per the Annual Energy Outlook (DOE, 1997). The crude mix would be based on the Petroleum Supply Annual and NPC estimates. Available swing crudes¹ would include Saudi Arabian Light, Saudi Arabian Heavy, United Kingdom Brent and United Kingdom North Sea crudes.
- Refinery product output would be based on Petroleum Supply Annual (DOE, 1996), extrapolated to the year 2004 with growth rates reported in the Annual Energy Outlook (DOE, 1997).
- Refinery investment in the refinery model would be based on a 15 percent return on investment. A 20 percent expansion of existing capacity would also be allowed at typical investment costs. Other investment would be subject to exponential economies of scale.
- Methyl tertiary butyl ether (MTBE) would be assigned a purchase price of 84 cents per gallon. This value is an average of a range of costs established by a recent study of the cost of variations of RFG by OTAG, conducted with the participation of states, and the oil and automobile industries.
- All prices and costs would be expressed in 1997 dollars.

The next section describes the results of the refinery modeling performed to date using these premises.

2. Summary of the Cost Calculation Methodology and the Cost of Reducing Gasoline Sulfur

In the analyses performed to date by EPA/DOE, two different versions of the ORNL-RYM refinery model were run to develop a range in costs for the program being investigated. The two versions of the refinery model are referred to as the ratio and ratio-free versions of the ORNL refinery model, because of the presence or absence of “ratio controls.” Ratio controls constrain the model from moving certain streams between refining processes based on the recommendation of industry experts who believe that they are required to ensure that the model

¹ Swing crudes are those crude oils which the refinery model can choose from to meet the incremental increases in energy demand caused by reducing gasoline sulfur.

accurately represents real refinery operations. Ratio controls tend to increase the projected costs. These two versions of the refinery model are explained further in a recent Oak Ridge National Laboratory's draft technical report which summarized an analysis of the cost of the Phase II RFG NOx standard.²

The cost estimates developed in the first phase of work performed by EPA/DOE assumed a program covering all gasoline produced in PADDs 1 and 3, which represents 75% of national gasoline production, California excluded. PADDs 1 and 3 provide a good starting point for estimating costs because of the large gasoline volume produced in these two PADDs, because the Northeast receives most of its gasoline from these two PADDs, and because of the range of technologies used in the refineries in these PADDs. While an estimate of the cost for sulfur control in either the 22- or 37-state OTAG scenarios could be made from the PADD 1 and 3 costs, a more detailed estimate would include an estimate of PADD 2 costs to supplement the costs obtained for PADDs 1 and 3. EPA and DOE plan to develop cost estimates for PADD 2 in the future.

Likewise, the cost of a nationwide sulfur control program could be estimated with costs from PADDs 1, 2, and 3, as these three PADDs produce the great majority of gasoline produced outside of California. EPA intends to perform additional refinery modeling runs to estimate the costs to refineries in PADD 4 (the Rocky Mountain area) and in PADD 5 outside of California ("PADD 5OC," which is the West coast, Hawaii and Alaska, without California). The average cost of sulfur reduction in these two PADDs is expected to be somewhat higher than the average cost in PADDs 1, 2, and 3 because of the small size of the refineries, and because the refineries are generally less complex which makes sulfur reduction more difficult and costly. However, because the gasoline production volume is much lower for PADDs 4 and 5OC, including the cost of sulfur reduction in these PADDs with the cost of sulfur reduction in PADDs 1, 2 and 3 would likely not significantly change the overall, national average cost estimate.

The series of calculations used to determine cost are summarized below in Tables B-2 to B-15. The cost in cents per gallon is calculated by dividing the change in objective function, which can be simply described as the change in net income of the group of refineries being modeled, by the volume of the gasoline pool experiencing the sulfur reduction. The next step in the procedure is to adjust the portion of the cost related to new capital investment to represent a range of rates of return on investment (ROI).³ The refinery model is run using a 15 percent ROI, to represent the decision-making process of refiners. The projected costs of sulfur control are

² Hadder, G.R., Oak Ridge National Laboratory, "Analysis of Costs and Refinery Impacts of Further Control of Gasoline Emissions - Draft, Incomplete Report," Draft 2, June 1, 1996.

³ The ROI is part of a mathematical relationship to determine the capital amortization factor, or the cost of capital, on a yearly basis. If the ROI is 15 percent, 10 percent or 8 percent, then the capital amortization factor would be (based on a depreciation and economic life of 13 years and a federal income tax rate of 34 percent) 0.232, 0.174 and 0.152, respectively. This means that with a 10 percent ROI, the yearly capital cost for a \$1 million investment would be \$174,000 per year (\$1MM x 0.174). Based on an 8 percent ROI, the capital investment cost would be \$152,000 per year.

determined using 8 and 10 percent ROIs, which more closely represent the actual return on capital invested.

To make these adjustments, the portion of the total cost of sulfur control which is related to new capital equipment must be determined. This is accomplished by simulating the accounting of capital costs performed by the model. The total capital cost investment (in dollars) is multiplied by the annual capital recovery factor for a ROI of 15 percent, or 0.242. This annual cost is then divided by the volume of low sulfur gasoline produced to estimate the per-gallon cost of the new capital equipment as determined by the refinery model. This process is then repeated for ROIs of 8 and 10 percent using annual capital cost recovery factors of 0.152 and 0.171, respectively. The difference between the per-gallon cost of new capital equipment with ROIs of 8 and 10 percent and that with an ROI of 15 percent is then subtracted from the total cost per gallon as estimated by the refinery model.

Other adjustments to the methodology were made to account for an apparent anomaly in how octane requirements in the gasoline pool were maintained, and to account for the fuel economy effect. An examination of the ORNL-RYM data output revealed a trend of increasing gasoline pool octane number $(R+M)/2$ in sulfur reduced gasoline pools compared to the base case. Since desulfurization generally results in octane loss, and it is unlikely that in making up octane refiners would exceed the required octane levels at an excess cost, these results were judged to be erroneous. To correct for this error, it is estimated that the oil industry spends on average about 4 cents per gallon to produce the 6 octane number spread between premium (93 $(R+M)/2$) and regular (87 $(R+M)/2$) grades.⁴ This cost rate per octane value difference was applied to the change in octane value from any particular refinery modeling case relative to the previous case, and the cost of sulfur reduction adjusted accordingly. The estimated cost of sulfur control must also be corrected for an expected reduction in fuel economy. The refinery model generally projects that refiners will increase their use of oxygenates to meet a tighter sulfur specification. Oxygenates contain less energy per gallon than non-oxygenated gasoline (81% percent of gasoline heat content for MTBE and 65% percent for ethanol). It is assumed that fuel economy is proportional to the energy content of gasoline. The decrease in total energy content of the finished gasoline is estimated from the increased oxygenate content of the affected gasoline pool relative to the previous refinery modeling case and multiplied by the retail cost of gasoline minus taxes. This cost of decreased fuel economy is then added to the sulfur control cost estimated by the refinery model.

Concerning the handling of costs, one challenge which had to be overcome was to determine to which gallons of gasoline the sulfur reduction costs would be allocated. This is important because as the cost of the gasoline sulfur reduction is allocated to a smaller or larger size of the gasoline pool, the per-gallon cost gasoline sulfur reduction is higher or lower, respectively. When a sulfur specification is imposed over the entire pool, including reformulated

⁴ U.S. DOE, "Table #32. Conventional Motor Gasoline Prices by Grade, Sales Type, PAD District and State" Petroleum Marketing Annual 1995, Energy Information Administration.

and conventional gasoline, the initial sulfur reduction occurs in the conventional pool only as RFG would already have lower sulfur levels as a result of the Phase II RFG NO_x standard. However, at some point, both pools experience sulfur reduction due to the sulfur standard. That point is difficult to judge as it generally occurs somewhere in between refinery modeling case runs. For the costs presented below, the cost of sulfur reduction is allocated to the conventional gasoline pool only down to 150 ppm, and is allocated to both the conventional and reformulated pool down to 100 and 40 ppm. While the sulfur reduction level at which both conventional and reformulated pools experience sulfur reduction differs for both PADD 1 and 3 models (for PADD 3 the convergence point is higher than 150 ppm, and for PADD 1 it is lower than 150 ppm), assigning the convergence point at the 150 ppm sulfur reduction point simplifies the cost calculations. For the refinery model runs with ratio controls, the gasoline pool size is determined by a weighted fraction of the cost for sulfur reduction determined by the model without ratio controls. The weighting determines what fraction of the range of gasoline pool size, which ranges from the conventional pool only to conventional and reformulated pool, that should be used, and is based on the costs for sulfur reduction from the basecase to 150 ppm relative to the cost of sulfur reduction from 150 to 100 ppm, for the same PADD model.

Table B-2. Calculation and Adjustment of Cost - PADD 1 Refinery Model Without Ratio Controls									
Change in Sulfur Level (ppm)	Obj. Funct Change (\$M/day)	Volume of Fuel Affected (Mbbbl/day)	Unadjust. cost (c/gal)	Change in Invest. (\$MM)	15% ROI Annual Amort. (c/gal)	10%ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)	8% ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)
450 to 150	275.5	290.5	2.26	262.1	1.42	1.01	1.84	0.90	1.73
150 to 100	245.5	755.1	0.78	110.4	0.232	0.164	0.711	0.15	0.69
100 to 40	1522.4	755.1	4.80	1204	2.52	1.78	4.06	1.58	3.86

Table B-3. Fuel Economy Adjustment of Cost - PADD 1 Refinery Model without Ratio Controls			
Change in Sulfur Level	Fuel Economy Adjustment (c/gal)	Fuel Economy Adjust Cost 10% ROI (c/gal)	Fuel Economy Adjust Cost 8% ROI (c/gal)
450 - 150	0.49	2.34	2.23
150 - 100	-0.02	0.68	0.68
100 - 40	0.58	4.56	4.36

Table B-4. Calculation and Adjustment of Cost - PADD 3 Refinery Model without Ratio Controls									
Change in Sulfur Level (ppm)	Obj. Funct Change (\$M/day)	Volume of Fuel Affected (Mbbl/day)	Unadjust. Cost (c/gal)	Change in Invest. (\$MM)	15% ROI Annual Amort. (c/gal)	10%ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)	8% ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)
322 to 150	1108	2957	0.892	671.6	0.359	0.253	0.787	0.225	0.759
150 to 100	1678	3677	1.09	1182	0.507	0.358	0.938	0.319	0.898
100 to 40	5815	3678	3.77	4845	2.08	1.47	3.15	1.31	2.99

Table B-5. Fuel Economy Adjustment of Cost PADD 3 Refinery Model without Ratio Controls			
Change in Sulfur Level	Fuel Economy Adjustment (c/gal)	Fuel Economy Adjust. Cost, 10% ROI (c/gal)	Fuel Economy Adjust Cost 8% ROI (c/gal)
322 - 150	0.33	1.07	1.04
150 - 100	0	0.83	0.79
100 - 40	0.01	3.14	2.97

Table B-6. Calculation and Adjustment of Cost - PADD 1 Refinery Model with Ratio Controls									
Change in Sulfur Level (ppm)	Obj Funct Change (\$M/day)	Volume of Fuel Affected (Mbbbl/day)	Unadjust. Cost (c/Gal)	Change in Invest. (\$MM)	15% ROI Annual Amort. (c/gal)	10%ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)	8% ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)
420 to 100	717	409	465	690.5	2.67	1.89	3.40	1.66	3.17

Table B-7. Fuel Economy Adjustment of Cost PADD 1 Refinery Model with Ratio Controls			
Change in Sulfur Level	Fuel Economy Adjustment (c/gal)	Fuel Economy Adjust. Cost, 10% ROI (c/gal)	Fuel Economy Adjust Cost 8% ROI (c/gal)
420 - 100	0.34	3.73	3.51

Table B-8. Calculation and Adjustment of Cost - PADD 3 Refinery Model with Ratio Controls									
Change in Sulfur Level (ppm)	Obj Funct Change (\$M/day)	Volume of Fuel Affected (Mbbl/day)	Unadjust. Cost (c/gal)	Change in Invest. (\$MM)	15% ROI Annual Amort. (c/gal)	10%ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)	8% ROI Annual Amort. (c/gal)	Adj. Cost (c/gal)
450 to 100	4808	3405	3.41	3787	1.78	1.26	2.88	1.11	2.74

Table B-9. Fuel Economy Adjustment of Cost PADD 3 Refinery Model with Ratio Controls			
Change in Sulfur Level	Fuel Economy Adjustment (c/gal)	Fuel Economy Adjust. Cost 10% ROI (c/gal)	Fuel Economy Adjust Cost8% ROI (c/gal)
367 - 100	0.35	3.18	3.04

Table B-10. Volume-weighted PADD 1 and 3 Cost of Sulfur Reduction, Based on the Refinery Model Without Ratio Controls, 10% ROI				
Sulfur Reduction		PADD 1	PADD 3	Volume Weighted PADDs 1 and 3
to	Cost (c/gal)	2.34	1.07	1.18
150 ppm	Volume affected (Mbbl/day)	290.5	2957	3248
150 to	Cost (c/gal)	0.68	0.829	0.80
100 ppm	Volume affected (Mbbl/day)	755.1	3677	4433
100 to	Cost (c/gal)	4.56	3.14	3.38
40 ppm	Volume affected (Mbbl/day)	755.1	3678	4433

Table B-11. Volume-weighted PADD 1 and 3 cost of Sulfur Reduction, Based on the Refinery Model with Ratio Controls, 10% ROI				
Sulfur Reduction		PADD 1	PADD 3	Volume Weighted PADDs 1 and 3
to	Cost (c/gal)	3.73	3.19	3.19
100 ppm	Volume affected (Mbbl/day)	409	3405	3814

Table B-12. Volume-weighted PADD 1 and 3 Cost of Sulfur Reduction, Based on the Refinery Model Without Ratio Controls, 8% ROI				
Sulfur Reduction		PADD 1	PADD 3	Volume Weighted PADDs 1 and 3
to	Cost (c/gal)	2.23	1.04	1.15
150 ppm	Volume affected (Mbbl/day)	290.5	2957	3248
150 to	Cost (c/gal)	0.678	0.789	0.776
100 ppm	Volume affected (Mbbl/day)	755.1	3677	4433
100 to	Cost (c/gal)	4.36	2.97	3.21
40 ppm	Volume affected (Mbbl/day)	755.1	3678	4433

Table B-13. Volume-weighted PADD 1 and 3 cost of Sulfur Reduction, Based on the Refinery Model With Ratio Controls, 8% ROI				
Sulfur Reduction		PADD 1	PADD 3	Volume Weighted PADDs 1 and 3
to	Cost (c/gal)	3.51	3.04	3.14
100 ppm	Volume affected (Mbbl/day)	409	3405	3814

Table B-14. Summary of Volume-Weighted, PADD 1 and 3 Sulfur Reduction Costs (cents/gallon)			
Sulfur Level	Base to 150 ppm	Base to 100 ppm	Base to 40 ppm
10 Percent ROI	1.2 -1.9	2.0 -3.2	5.4 -8.5
8 Percent ROI	1.1 -1.8	1.9 -3.0	5.1 -8.0

3. Estimating the Costs for Individual Refiners

While most gasoline sulfur control cost estimates, including the preliminary estimates presented above, represent costs to the average refiner, it is important to consider the range of costs expected to be experienced by individual refiners. Several years ago, EPA and DOE prepared a draft report which assessed the costs to the refining industry of various gasoline quality changes, and in the process developed a cost differential between “sulfur challenged” refineries and the refineries in the rest of PADD 3.⁵ The term “sulfur challenged” refinery was defined based on three criteria: relatively large capacity (specifically, 100-350 thousand barrels per day, which demonstrated that high costs and difficulties in complying with new requirements are not limited to small refineries), no FCC hydrotreating capability, and 1990 average gasoline sulfur levels above 450 ppm. Based on this analysis, these challenged refineries in PADD 3 were estimated to expend 1 cent per gallon just to bring their sulfur levels down to the PADD average gasoline sulfur level, which was about 320 ppm. From there, the challenged refineries would incur 0.7 c/gal more than the rest of the PADD to control gasoline sulfur levels down to an average of 150 ppm. Thus, some refiners are expected to incur substantially higher costs than other refiners for gasoline sulfur reduction.

Another study, performed by Wright-Killen, has also explored the potential impact on the refining industry of a gasoline sulfur program. This study estimated that a number of refineries nationwide could be in danger of closing if a low sulfur (about 40 ppm) gasoline program were pursued nationally.⁶ These refineries at risk produce about 10 percent of U.S. gasoline production. The reasons given for forecasting this financial risk is that these refineries currently lack gasoline sulfur removal equipment, have difficulty in obtaining capital due to a relatively poor financial standing, and must compete with other refiners which are better prepared to meet such requirements. EPA staff have reviewed the conclusions in this study and believe that this estimate of potential refinery closures represents the high end of a likely range. EPA’s position is based in part on the fact that some experts in the industry have concluded that various, compelling reasons exist which keep refiners in business, even when faced with financial hardship.^{7,8,9}

⁵Hadder, G.R., Oak Ridge National Laboratory, “Analysis of Costs and Refinery Impacts of Further Control of Gasoline Emissions - Draft, Incomplete Report,” Draft 2, June 1, 1996.

⁶ Hobbs, Horace, Ernst and Young-Wright Killen, Low Sulfur Gasoline Implementation Issues, Presentation at the CRC Symposium on Conventional and Emerging Technologies for Sulfur Removal from Gasoline, August 1996.

⁷ Comments by Jeff Utley, Refinery Manager, Flying J. Inc., at a Hart-IRI conference entitled “Telling it like it is,” summarized in Fuel Technology and Management, July/August, 1996.

⁸ Stetzer, C. Martin, Price Waterhouse L.L.C., Redefining the Context of Refinery Pacesetter Performance, 1997 NPRA Annual Meeting, March 16 - 18, 1997.

⁹ Wright-Killen, Clean Air Rules Could Wipe Out 1.5 million b/d in U.S. Refining Capacity, Oil and Gas Journal, December 28, 1992.

Appendix C

Relationship Between Per-Gallon and Averaging Standards

The purpose of this analysis is to estimate the average sulfur levels which would result from various per-gallon caps on gasoline sulfur content. The refinery cost estimates available to EPA are based on average costs to refiners in a given region of the country. Existing refinery models are not capable of estimating the average costs to the industry of a cap. However, as discussed in the main body of this paper, there are several factors that would likely lead to a cap being a more effective means of sulfur control than a standard based on the average sulfur level. The analysis presented here is an initial attempt to estimate the average sulfur levels which would likely result under various cap standards so that the costs presented in this report (applicable to average sulfur levels) could be associated with various cap standards.

API recently suggested a possible methodology for relating caps and averages based on an analysis of sulfur levels in batches of gasoline produced by U.S. refineries.¹ API assumed that the 90th percentile sulfur level from a refiner's batches of fuel would represent the cap achievable by that refiner. API presumed that the 10 percent of the batches with the highest sulfur levels could be reduced to below the 90 percentile level at an insignificant cost. The average sulfur level of all of the batches produced by the refinery would represent the average level that would result from meeting the per-gallon cap.

Based on this premise, API estimated the average sulfur levels associated with two different caps using data from the 1996 gasoline survey performed by API and NPRA.² API found that a cap on gasoline sulfur levels of 300 ppm for regular grade gasoline could result in an average sulfur content of about 200 ppm. Similarly, a cap of 200 ppm could result in an average sulfur content of 145 ppm, although the estimates for individual refiners ranged from 80-180 ppm.

After viewing the API analysis, EPA performed a similar analysis utilizing more data and additional percentiles. Specifically, EPA used conventional gasoline compositional data submitted in 1996 by the refining industry to meet the reporting requirements of the RFG and anti-dumping programs. In EPA's analysis, refiners with similar average gasoline sulfur levels were first grouped together. The distribution of gasoline sulfur levels in the regular grade gasoline batches of each group of refineries was then analyzed. (Only the regular grade batches need to be evaluated since premium gasoline, which is already relatively low sulfur, is not expected to be directly affected by a cap (unless if the per-gallon sulfur standard is very

¹Letter from Tim Hogan, API, to Charles Freed, U.S. EPA, October 10, 1997.

²American Petroleum Institute and National Petroleum Refiners Association, "Survey of Refining Operations and Product Quality," Final Report, July 1997.

stringent)). In addition to determining the 90th percentile of the batch gasoline sulfur levels as suggested by API, the 75th, 80th, and 95th percentiles were determined as well. The results of this analysis are summarized in Table C-1 below.

Prior to reviewing the results of this analysis, a couple of limitations should be noted in the potential applicability of this methodology. Refiners with the lower average sulfur levels are likely producing these low sulfur levels by processing low-sulfur crude oils, not because of sulfur reduction processing equipment implemented to meet a sulfur reduction standard. Thus, the relationship between potential sulfur caps and averages at the lower sulfur levels could be very different from that estimated here. Refiners currently have no incentive to minimize the maximum sulfur levels of individual batches produced through out the year. Their actions could be quite different under a cap. Also, the data analyzed here are not volume-weighted. Thus, if gasoline sulfur level is somehow associated with refinery size or if the batches produced by a particular refinery vary in volume, this analysis could have a bias.

There is also the issue of which (if any) of the percentiles actually represents the cap associated with the average of the batches of fuel. API recommended the 90th percentile. However, API used the 90th percentile of the whole gasoline pool while EPA only evaluated batches of regular grade gasoline. API's 90th percentile is roughly equivalent to the 85th percentile of regular grade gasoline (i.e., halfway in between the 80th and 90th percentiles shown in Table C-1.) (This equivalency presumes that none of the premium batches is above the 90th percentile.) As mentioned above, API estimated that sulfur caps of 300 and 200 ppm would result in average sulfur levels of 200 and 145 ppm. The results in Table C-1 indicate that these average levels more closely resemble the 75th percentiles as opposed to the 85th percentiles.

There are few actual examples of sulfur caps in the U.S. and elsewhere which could also be used to assess the relationship between a cap standard and the resulting average levels. One example is the 300 ppm gasoline sulfur cap which existed in California prior to California Phase II RFG, which resulted in an average sulfur level of 150 ppm. That cap/average relationship corresponds to the 95th percentile, based on EPA's analysis. That example, however, may not be representative of the rest of the country since California refiners generally have substantial hydrocracking capability to process the dirty feedstocks being processed and thus would tend to produce lower sulfur gasoline even in the absence of a cap.³ While not gasoline, another example of a cap is the federal 500 ppm limit on the sulfur content of highway diesel. That cap results in an average sulfur level of 340 ppm in the highway diesel sulfur pool.⁴ Based on the results in Table C-1, this cap/average relationship roughly corresponds with the 80th percentile. Again, the applicability of this relationship is limited because it is based on the average diesel sulfur level, which is controlled by a slightly different desulfurization technology than is gasoline. In Japan, refiners must meet a 100 ppm sulfur cap, and average gasoline pool sulfur

³See the discussion in Chapter III, Section B: Refinery Operations Affecting Sulfur.

⁴David Korotney, MEMORANDUM to Susan Willis, "A review of current and historical nonroad diesel sulfur levels," March 3, 1998.

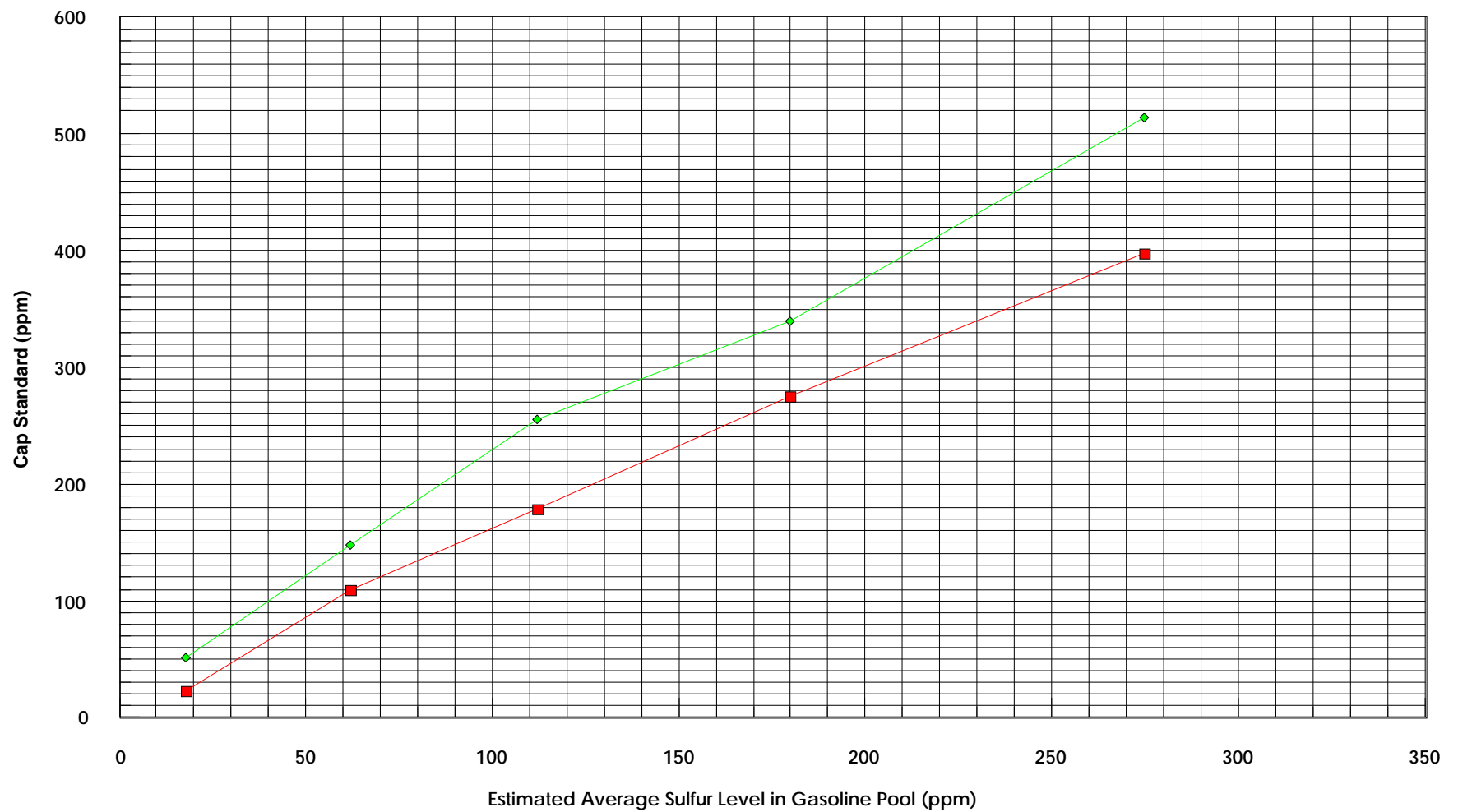
levels there are about 30 ppm. Although not necessarily representative of U.S. refiners, this relationship between the cap and average sulfur level is more consistent with the 95th percentile. It is important to assess how the relationship in Japan between the average gasoline sulfur level and the gasoline sulfur cap would apply to such a relationship here in the U.S., taking into account the differences in refinery capability, crude oil slate, and other fuel sulfur or emission control standards which may be affecting gasoline sulfur levels.

Based on this assessment of the likely average sulfur level which would result from a cap on gasoline sulfur levels, a preliminary range of average sulfur levels can be estimated from suggested cap values. Since significant uncertainty exists in this methodology, the range will encompass all the cap/average relationships derived above. These relationships are summarized in the figure below where the two curves mark the upper and lower boundaries of the range of the above estimates. One observation which can be made from applying this relationship, presuming it does indeed properly estimate the difference between a per-gallon cap and average pool gasoline sulfur level, is that as the cap is increased in stringency, the spread between the average and cap sulfur levels decreases in absolute terms and increases in relative terms. This is evident in the increased slope at lower sulfur levels.

Table C-1: Relationship of the Percentiles of Sulfur Levels in Regular Summertime Gasoline Batches to the Mean Sulfur Level of the Gasoline Pool for U.S. Refineries								
Mean Sulfur Level of Refinery	Number of Refineries	Mean Sulfur; Regular Grade (ppm) ^a	Mean Sulfur; Premium Grade (ppm) ^a	Calculated Pool Sulfur Level (ppm) ^b	75% ^c (ppm)	80% ^c (ppm)	90% ^c (ppm)	95% ^c (ppm)
All Data Analyzed	73	338	145	270	398 (0.85)	417 (0.81)	476 (0.71)	520 (0.65)
S<50 ppm	7	19	17	18	23 (0.83)	24 (0.78)	39 (0.49)	51 (0.37)
50<S<100	5	80	28	62	110 (0.73)	118 (0.68)	133 (0.60)	148 (0.54)
100<S<200	13	140	60	112	179 (0.78)	189 (0.74)	226 (0.62)	255 (0.55)
200<S<300	16	228	92	180	275 (0.83)	289 (0.79)	317 (0.72)	340 (0.67)
300<S<400	10	334	167	275	398 (0.84)	418 (0.80)	464 (0.72)	514 (0.65)

- a. The mean sulfur level represents the average refinery average of batches for those refineries with average sulfur levels within the range.
- b. Pool average sulfur levels are calculated assuming that 65 percent of the pool is regular grade and 35 percent is premium grade.
- c. Values in parentheses represent the percent that the mean sulfur level represents of the sulfur level at that percentile.

Estimated Relationship Between a Cap Sulfur Standard and Gasoline Pool Average Sulfur Level



Appendix D

Diesel and Gasoline Desulfurization in the Refinery

In addition to examining the need for gasoline sulfur reductions in the context of future light-duty vehicle/truck emission standards, the upcoming emission standards for diesel engines provides compelling reason to examine the need for changes to diesel fuel. In particular, the potential need for diesel sulfur reductions in the near future would be important to study because there are associations between how a refiner might desulfurize both gasoline and diesel fuel. These associations would make it advantageous for many refiners to address sulfur reduction requirements of both gasoline and diesel at the same time. Even if refiners are not required to control both fuels at the same time, if they are at least aware of impending diesel sulfur regulations, then they could invest in gasoline sulfur reduction, or respond in other ways, to facilitate a lower capital or operational cost for meeting a diesel sulfur requirement at a later date. There are several strategies which refiners could apply to address gasoline and diesel concurrently which would reduce the cost of addressing each individually. These include investments in larger refinery processing units which could cover the needs of both requirements, investments in different types of processing units that could achieve both fuel changes at a lower overall investment, or perhaps changes in the raw material and product slate.

Before investigating these options in more detail, it would be useful to examine the configuration of two typical refineries which produce motor vehicle fuels. One refinery is rather complex, which makes it capable of using a heavier, higher sulfur crude oil to make a wide range of refined products. The complex refinery is also capable of producing a larger fraction of its products as gasoline, and could more easily produce reformulated gasoline. This refinery is shown in Figure D1a. The second typical refinery is a simpler refinery with less processing capability, and is shown in Figure D2a. The various units within these representative refineries are summarized below in Table D-1.

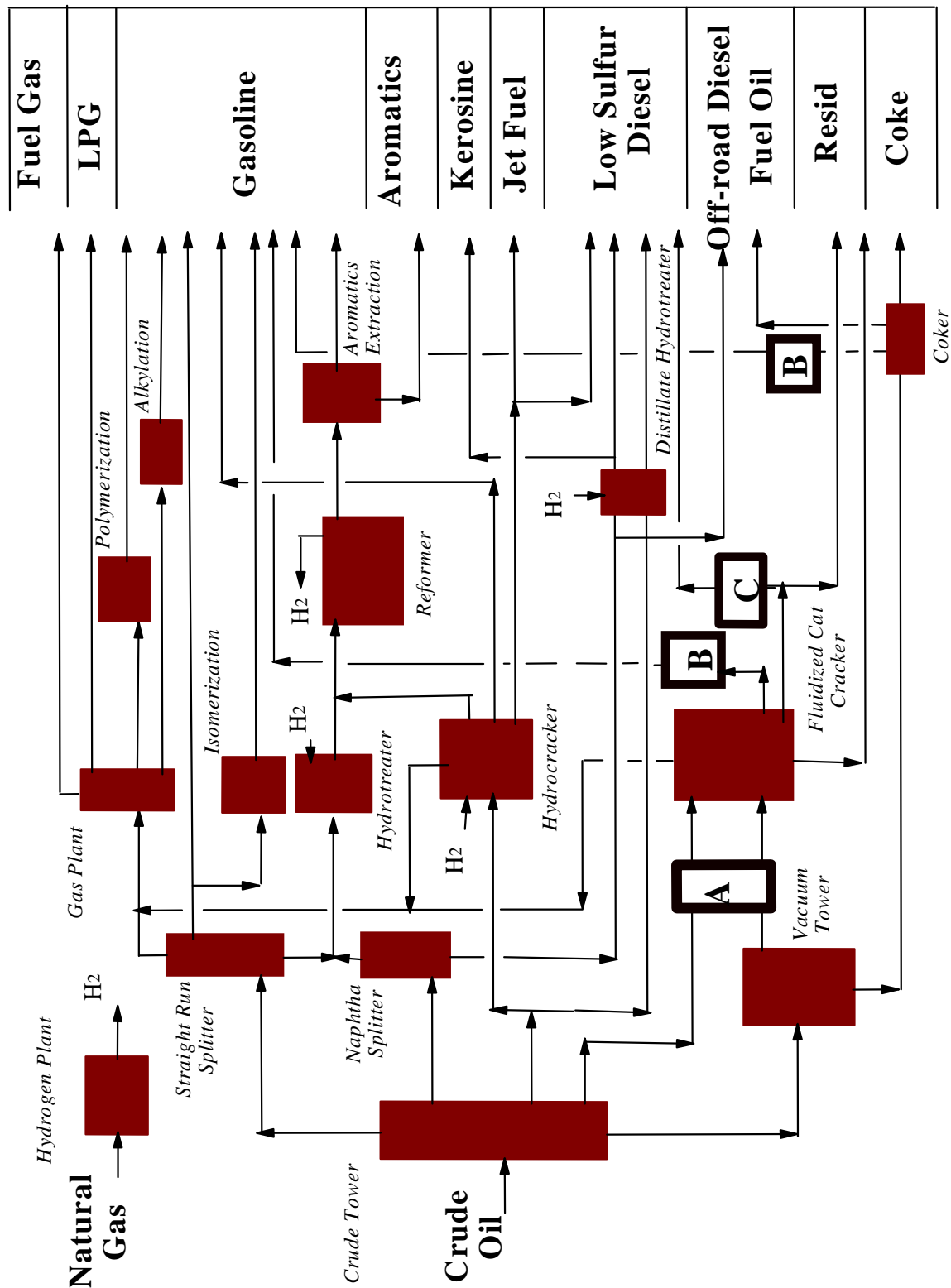


Figure D1a: Diagram of a Typical Complex Refinery

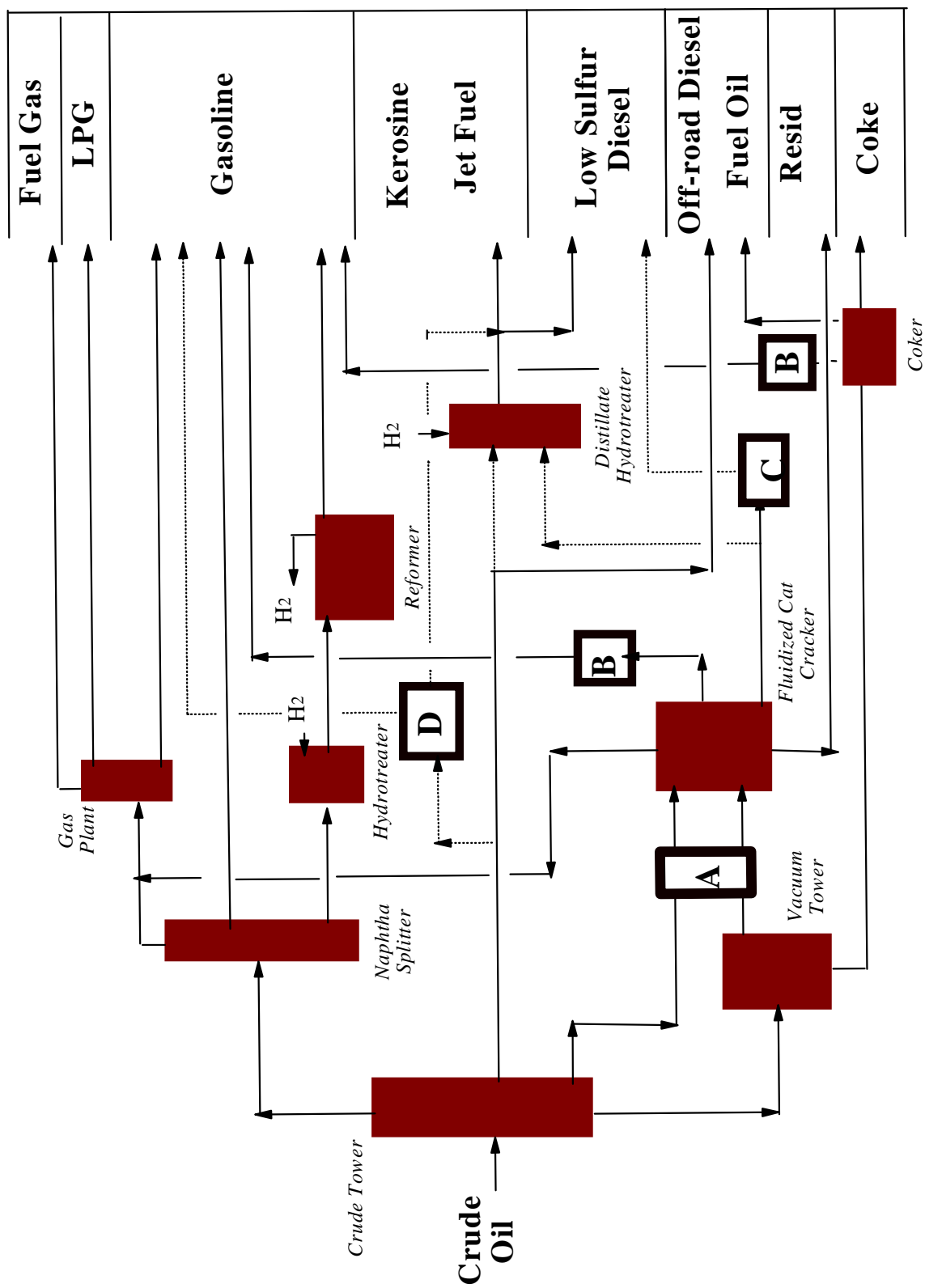


Figure D2a: Diagram of a Typical Refinery

Table D-1. Summary of Principal Refinery Processing Units and their Role in Gasoline and Diesel Refining			
Unit Name	Affect Gasoline?	Affect Diesel?	Role in the Refinery
Crude Tower	Y	Y	Distill crude oil into various streams for refining, distillate and gasoline cuts may go directly to blending
Vacuum Tower	Y	Y	Distill crude tower bottoms into streams for refining
Naphtha Splitter	Y	N	Distill naphtha into streams for refining
Straight Run Splitter	Y	N	Distill volatile naphtha into streams for gasoline refining
Gas Plant	Y	N	Distill very volatile streams for refinery fuel, LPG sales and for further refinery processing to produce gasoline
Fluidized Cat Cracker	Y	Y	Breaks large molecules into smaller ones for making more marketable refined products such as gasoline and diesel
Hydrocracker	Y	Y	Removes impurities while breaking large molecules into smaller ones, makes low sulfur refined products
Distillate Hydrotreater	N	Y	Reduces sulfur in distillate blendstocks for meeting low sulfur needs
Reformer Hydrotreater	Y	N	Reduces sulfur in feed to reformer which uses a sulfur sensitive catalyst
Reformer	Y	N	Rearranges molecules to make aromatics which improves gasoline octane; makes hydrogen for desulfurization
Isomerization	Y	N	Makes branched chain molecules out of straight chain molecules to improve octane value of naphtha
Alkylation, Polymerization	Y	N	Joins together very small molecules to make gasoline blendstocks with high octane value
Hydrogen Plant	Y	Y	Makes hydrogen from natural gas for desulfurization

A number of observations can be made from these figures concerning the production of gasoline and diesel. First, gasoline is often produced from a number of different units, all of which are designed to either convert other boiling stocks into gasoline blendstocks, or to improve the octane quality of gasoline. Conversely, diesel is mostly made up of straight run streams; the rest is a result of minimal processing (streams from the fluidized catalytic cracker (FCC) being the critical exception). Outside of the initial distillation, gasoline and diesel blendstocks are created from the same units which are designed to crack the heavier part of the crude oil into more marketable products. These units are the FCC, the hydrocracker and the coker. Even though these refining units do not comprise a large volumetric overlap between the production of gasoline and diesel, when considering the total amount of sulfur which ends up in gasoline and diesel, the FCC and coker refinery processing units provide a substantial contribution. These two

figures also show that refineries in the U.S. are already equipped with some facilities for hydrotreating distillate to make lower sulfur diesel and other products. However, the hydrotreating for these streams is moderate, as they are only designed to reduce diesel sulfur levels to meet the 500 ppm federal diesel sulfur standard.¹ Some sulfur reduction units will likely be added in those refineries producing gasoline to meet the year 2000 Phase II RFG standards.

A number of possible processing changes could be made in the refinery to reduce the sulfur content of gasoline, diesel fuel, or both fuels. For gasoline, these are summarized in Chapter III of this paper. These processes include hydrotreating of FCC gasoline blendstock outputs, hydrotreating the feed to the FCC unit, and using hydrocrackers. Diesel desulfurization involves similar processes. These include hydrotreating of diesel blendstocks (from the FCC or other units), hydrotreating the feed to the FCC unit, and using hydrocrackers.

Hydrotreating the FCC gasoline and hydrotreating diesel blendstocks are processes with no overlap in the hydroprocessing units themselves, since these are essentially “end of the pipe” treatment processes for these two refined products (shown as units “B” and “C”, respectively, in the figures above). However, there still may be economic advantages to implementing these two processes at the same time based on the need to provide a more economical incremental supply of hydrogen or additional utilities. Refiners could install a larger hydrogen production facility which would provide a lower cost supply of hydrogen for the hydrodesulfurization.

Hydrotreating the FCC feed affects the sulfur levels of both gasoline and diesel (shown as unit “A” in the figures above). This is because the feed hydrotreater reduces the sulfur level in the entire feed to the FCC unit, and a large portion of the FCC unit product stream ends up in gasoline and diesel. Since the heaviest part of crude oil contains the most sulfur, these streams will contain much more sulfur than other gasoline and diesel blendstocks, except for coker streams. FCC feed hydrotreating could be a more cost-effective option if both gasoline and diesel sulfur levels are controlled, since it reduces the sulfur levels from both fuels, and since the hydrogen supply and other utility needs could be met for both fuels at the same time. In addition, FCC feed hydrotreating improves the performance of the FCC, which would improve the product yields of that unit.

Another alternative as part of a strategy to reduce both gasoline and diesel sulfur levels is to install a hydrocracker. Hydrocrackers (shown as an existing unit in Figure D1a and as unit “D” in Figure D2a) convert the heavier parts of crude oil into compounds which can be used in gasoline and diesel fuel. However, unlike an FCC unit, a hydrocracker removes much of the sulfur present at the same time, unlike the FCC unit, which leaves the sulfur in the product streams. As stated earlier in this report, some refiners use hydrocrackers to process less desirable feedstocks which would be troublesome to treat with methods other than with hydrocracking. Alternatively, by investing in hydrocracking technology for their refinery, a refiner could change

¹In-use, highway diesel fuel sulfur average levels are about 340 ppm.

its crude slate to cheaper, higher sulfur crude oils or other similar feedstocks at a raw material cost savings.

Finally, to provide more flexibility and to achieve low levels of sulfur, a refinery may install several sulfur reduction units. For example, refiners without hydrocrackers could install both a hydrocracker and FCC gasoline and distillate hydrotreaters. This may allow the refinery to meet stringent sulfur reduction requirements and offset some of their costs with purchasing higher sulfur feedstocks. Another alternative would be for refiners to install a hydrocracker and FCC feed hydrotreating. However, many refiners may not be in the position financially to make such large capital investments, even with anticipated improvements in refinery profit margins.

EPA and DOE plan to investigate the impact of low sulfur diesel fuel requirements on the cost of gasoline sulfur control using the ORNL-RYM refinery model. The model will be used to estimate the cost and required capital equipment needed to simultaneously control diesel and gasoline sulfur. These processing changes and resulting costs will be compared to those resulting from the control of gasoline sulfur alone to assess whether there is much potential for synergies. However, the results will be limited in part by the current configuration of the refinery model. The ORNL-RYM model has never been used to simulate diesel sulfur control to such low levels and there is some question about whether it contains sufficient refinery modeling capability to generate realistic cost estimates. The model's capability will be assessed after performing several initial modeling runs.